FILED
9-23-16
10:27 AM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

ADMINISTRATIVE LAW JUDGE RULING DIRECTING PRODUCTION COST MODELING REQUIREMENTS

Summary

This ruling provides direction for modeling of system and flexibility needs for the electricity system, utilizing production cost models, in order to ensure comparability of results from different modeling analyses in this and/or future Commission proceedings. The modeling standards included in the attachment to this ruling result from work by Commission staff and parties in the prior long-term procurement planning (LTPP) rulemaking (R.) 13-12-010. This modeling direction is provided in a ruling at this stage because of the need for ongoing work to put these modeling requirements into the larger modeling context for purposes of the integrated resource planning (IRP) requirements just commencing as a result of Senate Bill (SB) 350 (DeLeon, 2015). The direction in this ruling shall be in place until such time as it is replaced by a subsequent ruling or decision of the Commission on overall modeling requirements for IRP and LTPP need determination and/or procurement authorization purposes.

1. Background

Production cost modeling methodology work began in the previous long-term procurement planning (LTPP) proceeding, rulemaking (R.) 13-12-010. The purpose was to evaluate the need for additional flexible resources, *i.e.*, resources that are able to ramp up or down in response to fluctuating supply and demand to manage the increasing levels of distributed energy resources (DERs) and variable energy resources (VERs). In order to perform this evaluation, the LTPP proceeding made use of technical studies assessing the ability of the expected future generation fleet to meet future electricity demand. Studies were conducted and submitted in R.13-12-010 by Southern California Edison (SCE) and the California Independent System Operator (CAISO). While the models used in these studies have been under development for several years, the previous LTPP proceeding sought to use them to inform flexible resource procurement decisions for the first time.

The results of those studies highlighted a potential need for additional flexibility in the electric system to follow both load fluctuations and VER output under a range of possible futures. However, the majority of parties to the proceeding, including those who took part in the previous modeling efforts, cautioned the Commission about making procurement-related decisions based on the initial results of the studies. Instead, the Commission began to focus on altering the models and/or their methods of application to enhance their transparency and accuracy for future use in procurement authorizations.

This most recent iteration of work on modeling methodologies began with a March 25, 2015 administrative law judge (ALJ) ruling in R.13-12-010[1] setting forth a number of issues with the previous modeling work and concluding that "there is not sufficient evidence at this time to authorize additional flexible or

---

[1] *See* ALJ Ruling discontinuing Phase 1a and setting forth issues for Phase 1b, issued March 25, 2015, available online at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M148/K825/148825409.PDF

system capacity through 2024" and "there is both sufficient time and a critical need to further develop modeling efforts to inform the 2016 LTPP proceeding regarding the need for flexible capacity through 2026." The ruling recommended that the proceeding continue to focus on developing and validating models that can "accurately highlight and distinguish needs for both flexible and generic system resource attributes to maintain reliability, to investigate efficient solutions to potential operational flexibility events (such as over-generation events), and to set the stage for expanded future analyses which will balance the cost-effectiveness and GHG impacts of measures to ensure system reliability." The ruling further directed Commission staff to investigate the following modeling issues with parties in working groups and workshops:

1. Developing common definitions, metrics, and standards;
2. Identifying standard outputs; and
3. Validating stochastic and deterministic models and making technical improvements.

Numerous parties participated extensively in informal workshops, working group meetings, and an informal comment process hosted by Commission Energy Division staff in mid-2015.

Staff held a series of technical discussions and solicited input from working group participants to create a roadmap for using the models in Commission decision-making. A preliminary Staff Proposal was shared with parties on July 27, 2015 and was presented and discussed during an August 4, 2015 workshop. Informal comments were solicited on August 6, 2015 and received by staff on August 13, 2015.

Those efforts culminated in an ALJ ruling issued in R.13-12-010 on November 16, 2016[2] which disseminated a formal Staff Proposal on modeling methodologies and sought comment from parties on a series of questions in the ruling, plus the attached Staff Proposal overall.

On December 4, 2016, 14 parties filed opening comments;[3] reply comments were also filed on December 11, 2015 by 14 parties (a different set of parties than filed opening comments, with some overlap).[4]

In addition, on December 24, 2015 GPI filed a motion to strike the reply comments of CBD. CBD filed a response to GPI's motion on January 4, 2016, requesting that its comments not be stricken. An ALJ ruling issued February 2, 2016 in R.13-12-010 denied GPI's motion to strike CBD's comments, but allowed GPI to file an additional reply to CBD's reply comments. GPI filed those further reply comments on February 19, 2016.

2. Relationship to Current Activities

The work in the previous LTPP proceeding was undertaken in the context of a desire to gain confidence in modeling techniques designed to identify the

---

[2] ALJ Ruling is available online at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M155/K876/155876463.PDF

[3] Opening comments were filed by the following parties: California Energy Storage Association (CESA); California Environmental Justice Alliance (CEJA); California Independent System Operator (CAISO); California Large Energy Consumers Association (CLECA); Calpine; City of Redondo Beach (Redondo Beach); Green Power Institute (GPI); NRG Energy (NRG); Office of Ratepayer Advocates (ORA); Pacific Gas and Electric (PG&E); San Diego Gas & Electric (SDG&E); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS) and Sierra Club, jointly; and Wellhead Electric Company (Wellhead).

[4] Reply comments were filed by the following parties: CAISO; California Wind Energy Association (CalWEA); Calpine; CEJA; Center for Biological Diversity (CBD); CLECA; the Large Scale Solar Association (LSA); the Natural Resources Defense Council (NRDC); NRG; ORA; PG&E; Southern California Edison (SCE); TURN; and UCS and Sierra Club, jointly.

physical need for flexible capacity, in addition to generic capacity, to ensure a sufficiently reliable electricity system. While there seemed to be general stakeholder consensus that stochastic models might offer a better, or at least a valuable complementary methodology, for identifying those needs relative to the deterministic models on which the industry has relied for needs analyses for many years, there was a general lack of confidence in results delivered so far.

In parallel with the work in the previous LTPP proceeding, there has been ongoing work through the California Energy Systems for the 21st Century (CES-21) "flexibility metrics and standards project" collaborative research partnership between PG&E, SCE, SDG&E and Lawrence Livermore National Laboratory, authorized in D.12-12-031 and modified by D.14-03-029. Resolution E-4677 on October 2, 2014 further required that the project results be demonstrated using the assumptions and at least one of the scenarios adopted in the Commission's 2016 LTPP proceeding, and presented to the parties in that proceeding, which is now the proceeding in which this ruling is being issued.

In addition, the CAISO conducts ongoing modeling analyses to support its annual Transmission Planning Process (TPP). Certain CAISO special studies have also historically been used to inform aspects of the Commission's LTPP work.

Meanwhile, thinking among experts continues to evolve about how to define flexibility "need" and whether it is most appropriately analyzed for its physical characteristics or its economic implications or (most likely) both.

Finally, in this proceeding, the Commission is taking on the task of determining modeling requirements for the IRP requirements of SB 350, initially focusing on resource optimization modeling and not necessarily focusing in any depth on flexibility needs. It is foreseeable, however, that once the modeling framework for resource optimization analysis is more specifically defined, it will still lead back to a next step of analyzing requirements for flexibility resources and/or grid integration needs for intermittent resources, given the increasing renewables requirements that also emanate from SB 350. Any such flexibility need modeling will take place within and be informed by the context of the IRP resource optimization analysis.

3. Interim Modeling Requirements

Given this shifting landscape, it is premature for the Commission to solidify requirements for production cost modeling to analyze system and flexibility needs in a formal Commission decision, even though that course of action had been previously planned in R.13-12-010. Instead, this ruling serves as an interim directive to parties conducting production cost modeling, particularly where focusing on identifying system and flexibility needs, until further action of the Commission. This will assist with comparability of analyses and results, while still allowing for an evolving overall (broader) framework for modeling requirements to support IRP and LTPP requirements.

In addition, utilizing the modeling standards included in the attachment to this ruling titled "Production Cost Modeling Requirements," and then analyzing and comparing results, will assist all stakeholders, including the Commission, in validating and building confidence in the modeling tools and techniques for this type of analysis.

The attachment to this ruling refers to a requirement for any party presenting modeling results to the Commission to utilize a "Reference Case" to facilitate comparability of results across different types of modeling work and scenarios or cases analyzed. At this time, the most appropriate "Reference Case" to use is contained in the May 17, 2016 Assigned Commissioner's Ruling

Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016-17 Transmission Planning Process and Further Commission Proceedings in Rulemaking 13-12-010, and is defined therein as Scenario 2: "Default Scenario with mid-level additional achievable energy efficiency (AAEE) sensitivity." This scenario contains all of the requirements of SB 350 except not the most aggressive assumption about AAEE, chiefly because not enough analysis has yet been done about the feasibility of the more aggressive AAEE assumptions; work on this is ongoing both at this Commission and at the California Energy Commission, the latter of which has responsibility for both the electricity demand forecast for the state and for the setting of energy efficiency goals associated with SB 350.

The "Default Scenario with mid-level AAEE sensitivity" and its designation as the "Reference Case" should not be confused with the scenarios that will likely be developed in the near future to address the resource portfolio development and optimization needs for IRP. It is likely that several new or additional scenarios will be developed in that IRP context to evaluate possible resource portfolios to meet the SB 350 greenhouse gas requirements, and the additional requirements of SB 32 (Pavley, 2016) recently signed by the Governor. When those new scenarios are sufficiently developed in the IRP work of this proceeding, the Commission will likely update the requirements currently being specified in this ruling for new IRP scenarios to be analyzed with production cost modeling.

In the meantime, given there is ongoing work both at the CAISO and as part of the CES-21 project, Scenario 2: "Default Scenario with mid-level AAEE sensitivity" should be used as the "Reference Case" referred to in the attachment to this ruling.

Further discussion about modeling needs and techniques to inform the resource portfolio development needed for IRP work will be forthcoming in this proceeding.

IT IS RULED that:

1. Entities conducting production cost modeling for purposes of analyzing system and flexibility needs for presentation at the Commission shall follow the requirements shown in the attachment to this ruling titled "Production Cost Modeling Requirements," until such time as this ruling is superseded by another ruling and/or decision of the Commission.
2. For purposes of comparability of results, entities conducting production cost modeling for purposes of analyzing system and flexibility needs for presentation at the Commission shall utilize, at a minimum, Scenario 2: the Default Scenario with the mid-level additional achievable energy efficiency sensitivity, described in the May 17, 2016 Assigned Commissioner's Ruling Adopting Assumptions and Scenarios for Use in the California Independent System Operator's 2016-17 Transmission Planning Process and Further Commission Proceedings in Rulemaking 13-12-010.

Dated September 23, 2016, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

ATTACHMENT

California Public Utilities Commission

Production Cost Modeling Requirements

9/21/2016

Table of Contents

Definitions and Reliability Metrics

This document defines terms and metrics solely to provide for a plain and common language for specifying guidance on production cost modeling to quantify system reliability and other performance targets that are intended to inform Commission proceedings. These terms and metrics are commonly used among planners and operators in the electric industry, often to describe real world electricity market and grid operation activities rather than to describe production cost models. Because these terms and metrics may be defined and used differently by others in the industry, care must be taken to not conflate the definitions and usages of others with those specified in this document. This document assumes the reader has basic knowledge of electricity markets and production cost models as the terms and definitions below are not exhaustive and only introduced as needed to facilitate the provision of modeling guidance.

Terms and Definitions

Event: An occurrence during the course of electric resource unit *commitment* and *dispatch* where generation could not be balanced with load, including the need to hold a certain amount of *operating reserves*. In the case of an over-supply of energy imbalance, example *events* are instances of *over-generation*, economic renewables curtailment, and under-commitment of reserves. In the case of an under-supply of energy imbalance, example *events* are instances of *loss-of-load* and under-commitment of reserves. These terms are more precisely defined below. The expected frequency, duration, and magnitude of such *events* can be used to assess the reliability level of an electric system.

Operating reserves: Any type of electric capacity used to support grid balancing including *contingency reserves*, *regulation* up/down, and *load following* up/down reserves. Note that the term *operating reserves* and its subcategories are not used uniformly in the electric industry.[1] For instance, the CAISO uses the term "operating reserves" to specifically mean "the combination of Spinning and Non-Spinning Reserve required to meet NERC and WECC[2] reliability standards and any requirements of the NRC[3] for reliable operation of the CAISO Balancing Authority Area."[4] The reader should take care not to conflate the CAISO's definition of "operating reserves" with this document's broader use of the term as described above. This document uses the terms *contingency reserves* to refer to spinning and non-spinning reserves, and *operating reserves* to collectively refer to *contingency reserves*, *regulation*, and *load following* reserves.

[1] The National Renewable Energy Laboratory (NREL) paper "Operating Reserves and Variable Generation" provides a technical overview of the different types of operating reserves and how they are used in North America and Europe: http://www.nrel.gov/docs/fy11osti/51978.pdf

[2] NERC: North American Electric Reliability Corporation; WECC: Western Electricity Coordinating Council

[3] Nuclear Regulatory Commission

[4] See the CAISO definition of operating reserve in the Business Practice Manual document here: https://bpmcm.caiso.com/BPM%20Document%20Library/Definitions%20and%20Acronyms/BPM_for_Definitions_and_Acronyms_V15_clean.docx

Contingency reserves: A type of *operating reserve* held to address rare contingency events such as the sudden loss of a large generator or a major transmission line. *Contingency reserves* consist of spinning and non-spinning reserves. In hourly production cost models, each Balancing Authority Area (BAA) shall be modeled to hold spinning and non-spinning reserves equal to 3% of hourly integrated load for each reserve type.[5]

Regulation: This refers to the ancillary service generally used to balance routine load and generation variability faster than the shortest market dispatch interval and has automatic centralized response requirements. In the CAISO market, resources can be re-dispatched by market activities on multiple time horizons, the shortest of which is five minutes. In hourly production cost models, required *regulation* upward and downward reserves are *committed* each hour to provide the capability to automatically balance any variability likely to occur within any of the five minute intervals of the hour.

Load following reserves: This refers to a modeling abstraction of a type of *operating reserve* used to balance routine load and generation variability across several market dispatch intervals typically within an hour, as well as forecast error regarding the next hour's load and generation. In hourly production cost models, required *load following* upward and downward reserves are *committed* each hour to provide ramping (up or down) capability sufficient to manage the expected load and generation variability and forecast error for that hour. *Load following reserve*, as described in this document, is not an actual ancillary service, nor an existing CAISO market product.[6] Rather, it is a proxy for more complicated sub-hourly market activities that adjust commitment and dispatch levels within the hour, which are usually not explicitly modeled by hourly production cost models.

How much *load following reserve* and *regulation* should a model commit for each hour is a question of increasing importance because of the perception that more reserves may be necessary to manage the increasing variability introduced by higher penetrations of wind and solar resources on the electric grid. The Modeling and Validating Load-Following and Regulation Requirements subsection later in this document provides guidance on calculating, validating, and documenting hourly *load following* and *regulation* requirements for hourly production cost models.

Commitment and ***Dispatch***: Unit *commitment* refers to scheduling (i.e. reserving or holding) a resource for a particular use during a particular hour. A resource could be *committed* to serve load, or *committed* to standby as an operating reserve during a particular hour. Unit *dispatch* refers to the actual operation of a resource to move to a particular output level. In the context of hourly production cost models, unit

---

[5] The modeling convention to hold reserves of 3% of load for each of spin and non-spin reserves was used in the modeling done in the 2014 LTPP proceeding and is intended to represent grid operations meeting the NERC reliability standard BAL-002-WECC-2, which states that contingency reserves shall be "equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation." Production cost models would be too complex if dynamically calculating reserves to hold based on hourly generation. Hence models use the proxy of 3% of load for each of spin and non-spin reserves.

[6] However, the CAISO is deploying a new flexible ramping market product with similarities to the load following modeling construct.

commitment and *dispatch* describes the simulated economic[7] operation of electric resources on the grid to balance generation and load at all times. For example:

- Resources *committed* to serve load during a particular hour are *dispatched* to provide energy during that hour.
- Resources *committed* as *contingency reserves* are not *dispatched* as part of normal grid operation – because contingencies such as the sudden loss of a large generator or transmission line are "infrequent events that are more severe than balancing needed during normal conditions."[8] However, *contingency reserves* that are held but not dispatched may also be producing energy if the units providing reserves must be turned on at a minimum operating level (i.e. Pmin) in order to be capable of quickly ramping up to respond to a contingency.
- Resources *committed* as *load following reserves* and *regulation* for a particular hour are *dispatched* to balance routine variability during that hour and is considered part of normal grid operation. In addition to whatever ramping of energy output that *load following* and *regulation* provide for routine balancing of intra-hour variability, these reserves may also be producing a certain level of energy in order to be capable of providing that reserve service. This is because a resource providing reserves may need to be turned on at a minimum operating level (i.e. Pmin) to be capable of ramping upward or set at a level above Pmin to be capable of ramping downward.

The terms unit *commitment* and *dispatch* also describe actual CAISO market activities which cover multiple market dispatch intervals, for example, hour-ahead, fifteen-minute, or five-minute. These market operations are usually too complex for an hourly production cost model to explicitly simulate. The above definitions of *commitment* and *dispatch* used to describe production cost models should not be conflated with the more specialized meanings these terms may have within the CAISO tariff.

Under-commitment: In the context of hourly production cost models, *under-commitment* refers to a model decision to *commit* less than the required amount of resources for a particular use during a particular hour. For example, if the model encounters an hour where it runs short of available resources to serve that hour's load, it will *commit* less than the required amount of *operating reserves* (i.e. *under-commit*) in order to free up capacity to serve load. (This also implies that no more resources are available to backfill reserves that are *committed* to serve load instead of provide reserves.) If the shortage of available resources is large enough, the model may have to *under-commit* all reserves (i.e. no reserves are *committed*) and must begin to *under-commit* resources to serve load (i.e. firm load curtailment).

---

[7] Typical production cost models employ a range of pricing assumptions to simulate economic hourly unit *commitment* and *dispatch.* Sometimes these prices are designed to help the model optimization engine achieve realistic hourly *commitment* and *dispatch* outcomes, rather than reflect realistic cost or market pricing outcomes. A second model run (using the unit *commitment* and *dispatch* outcome from the first run) or post-processing with price assumptions designed to reflect realistic economic consequences may be necessary to calculate accurate cost outcomes.

[8] See pp. 9-10 of this NREL paper on operating reserves: http://www.nrel.gov/docs/fy11osti/51978.pdf

Frequency Response Constraint: In hourly production cost models, the *frequency response constraint* refers to a model constraint to have certain amounts of certain types of generation within the CAISO BAA online at all times to ensure the CAISO can meet its obligations under the NERC BAL-003-1 standard. The current amounts and types of generation are defined in the May 2016 LTPP Assumptions and Scenarios Assigned Commissioner's Ruling,[9] or its successor document.

Loss-of-load: An instance during the course of *committing* and *dispatching* electric resources to serve load and provide reserve capacity where there is an under-supply of energy imbalance that <u>*could*</u> result in the curtailment of firm load. The point at which firm load is curtailed in a complicated electric system such as the CAISO's is rarely when all reserves are completely *under-committed*, i.e. no reserves; generally some amount of *operating reserves* are required at all times. A model (or an operator such as the CAISO in the real world) can decide to curtail firm load before under-committing all reserves, since the reserves are there to prevent even larger losses of firm load.

When there is forecast under-supply in the hour ahead, production cost models typically follow a priority order[10] by reserve type (similar to that in the CAISO market scarcity pricing mechanism) for *under-committing* resources to provide required reserves and serve load. Under such conditions, *load following*-up reserves are typically *under-committed* first, followed by relaxing of the *frequency response constraint*, followed by *under-commitment* of non-spinning, spinning, *regulation*-up, and finally *under-commitment* of generation to serve load for that hour (firm load curtailment). The threshold for deciding when *loss-of-load* occurs could be set at any point in the above unit *under-commitment* sequence, for example, as soon as *load following*-up reserves are under-committed, or only after complete *under-commitment* of all *operating reserves*.

To ensure consistent definitions and comparable results across study efforts by different organizations, this document defines that *loss-of-load* in hourly production cost models occurs at the point when the hourly required *load following*-up reserves and non-spinning reserves are both completely *under-committed* and the *frequency response constraint* is fully relaxed. (the model is still able to *commit* the required amounts of spinning reserve and *regulation*). This aligns with the priority order of *committing* resources in the CAISO market. It aligns with the idea articulated above that some amount of *operating reserves* are required at all times to prevent larger losses of firm load. It also aligns with the CAISO's definition of a "Stage 3 Emergency," a grid stress condition when *committed* spinning reserves fall to less than 3% of load and CAISO-directed firm load curtailment may potentially occur.[11]

Furthermore, *loss-of-load events* reported in hourly production cost models must be classified as one of two types: (1) capacity shortage driven and (2) flexibility shortage driven. For *loss-of-load events* as defined above, if there were no available resources (an available resource is one that is not on outage)

[9] The May 17, 2016 Ruling here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673

[10] This priority order description was adapted from CAISO testimony of Dr. Shucheng Liu served in Docket No. R.13-12-010, August 13, 2014, pp. 10-12.

[11] http://www.caiso.com/Documents/EmergencyFactSheet.pdf

in that hour, then the *loss-of-load event* is classified as capacity driven, otherwise it is classified as flexibility driven. In other words, when a model cannot commit or dispatch a resource that is otherwise available (not on outage), it must be because of a binding constraint limiting the operational flexibility of the resource (e.g. a physical constraint such as maximum ramp rate or minimum start time).

Over-generation: An instance during the course of *committing* and *dispatching* electric resources to serve load and provide reserve capacity where there is an over-supply of energy imbalance that cannot be managed by resource curtailment, including renewables curtailment,[12] and turning down and off all dispatchable[13] resources. The actions of turning down and off dispatchable resources may equate to *under-commitment* of reserves because units that would have been set to a minimum or higher output level to serve as *operating reserves* are instead turned down towards minimum output levels or even turned off in order to alleviate over-supply.

When a production cost model forecasts over-supply in the hour ahead for a particular BAA such as the CAISO area, this first manifests as low or negative market prices within the BAA. Under these conditions, exporting energy outside the BAA becomes economic, as does renewables curtailment[14] within the BAA. If economic exports and renewables curtailment are unconstrained then these mechanisms should be able to alleviate over-supply – and *over-generation*, as defined above, would not occur.

In reality, economic exports and renewables curtailment are not limitless and may be modeled with constraints, for example imposition of a net export limit or a cap on economic renewables curtailment energy for a given timespan.[15] Under these constraints, hourly production cost models typically follow a priority order[16] for actions to alleviate over-supply. First, the model manages over-supply (in the hour ahead within a particular BAA) by using all available economic exports and renewables curtailment and turning down dispatchable resources to their minimum operating levels, which may include some *under-commitment* of operating reserves such as downward hourly *load following* and *regulation*. Second, the

---

[12] Renewables curtailment means committing and dispatching renewable resources to curtail output when they would otherwise be producing energy (e.g. because the wind is blowing or the sun is shining).

[13] A dispatchable unit generally participates in the wholesale energy market and sets its output according to market activities, or can otherwise be directly controlled by the grid operator (e.g. the CAISO).

[14] Production cost models simulate wholesale electricity market operation and typically *dispatch* least costly units first and most costly units last according to pricing assumptions. During over-supply conditions (low or negative energy prices), most costly units are turned down first and least costly units are turned down last. Low/zero variable cost energy, i.e. renewables, are modeled to keep providing energy until market prices are low or negative, at which point renewables "economically" curtail, essentially getting paid to forego output.

[15] Assumptions for such model constraints are separately specified in the current proceeding's adopted planning assumptions and scenarios: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673

[16] The priority order description was adapted from the CAISO report filed in Docket No. R.13-12-010, May 8, 2015, p. 3: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K411/152411557.PDF

model turns off (shuts down) dispatchable resources which may include relaxing of the *frequency response constraint*, and some *under-commitment* of operating reserves such as upward hourly *load following*, *contingency reserves*, and upward *regulation*. If after turning down and off all dispatchable resources over-supply remains for the hour, this residual over-supply is counted as *over-generation*. The models used in the 2014 LTPP proceeding called this residual over-supply condition "unsolved over-generation" or "dump energy."

To ensure consistent definitions and comparable results across study efforts by different organizations, this document defines that *over-generation* in hourly production cost models occurs at the point when no more dispatchable resources can be turned off.[17] This definition of *over-generation* is intended to make it possible to compare different studies' reported over-supply conditions by precisely identifying the threshold for recording when *over-generation* has occurred, and distinguishing it from other outputs that are indicative of over-supply conditions.

In the real world, when over-supply is not sufficiently managed via normal (routine) market activities, an operator such as the CAISO can choose to manage residual over-supply using certain out-of-market measures (such as exceptional dispatch) and *under-commitment* of some but usually not all reserves. Hourly production cost models can quantify this residual over-supply by reporting the hour and magnitude of each type of reserve *under-commitment* and *over-generation*. Together these outputs can indicate how often the system approaches over-supply conditions that cannot be managed via normal market and operator activities.

Zone: Hourly production cost models generally represent transmission constraints between different geographic areas by dividing the entire WECC area[18] into *zones*, where transmission constraints between *zones* are explicitly modeled and transmission constraints within *zones* are not explicitly modeled. The models used in the 2014 LTPP proceeding divided the entire WECC area into 25 *zones*,[19] where 8 *zones*[20] represent California and the remaining 17 *zones* represent the rest of the WECC area. Production cost modelers have discretion to model areas outside of California as fewer or greater than 17 *zones* but shall model areas inside of California at least as granular as the 8 *zones* identified in the 2014 LTPP

---

[17] The *over-generation* threshold in a model is not defined by certain levels of *under-commitment* of *operating reserves* because even when all dispatchable resources are turned off, some upward *operating reserves* can still be *committed* if provided by units that do not produce energy while functioning as a reserve (e.g. battery storage or other quick start resources).

[18] WECC: Western Electricity Coordinating Council. The WECC (area) is also commonly used as shorthand for the western half of North America that is served by the Western Interconnection.

[19] For further description of production cost model zones and the 25 zones used in the 2014 LTPP proceeding models, see CAISO testimony of Dr. Shucheng Liu served in Docket No. R.13-12-010, August 13, 2014, pp. 12-13

[20] Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LDWP), PG&E Bay Area (PG&E_BAY), PG&E Valley (PG&E_VLY), SCE, SDG&E, Sacramento Municipal Utility District (SMUD or BANC), and Turlock Irrigation District (TIDC)

proceeding models. These 8 zones are listed in the table below with a mapping to geographical areas represented in the California Energy Commission's Integrated Energy Policy Report "Load Serving Entity and Balancing Authority Forecasts" Form 1.5a.[21] Certain model outputs shall be reported at least by *zone* granularity or region granularity, as specified in the Model Output Requirements section of this document and shown in the table below.

Table 1: Modeled Zones and Regions

IEPR Demand Forecast Form 1.5a Balancing Authority/ Agency Categories (Rows)	Model "Zones"	Model "Regions"
Greater Bay Area Subtotal	PG&E_BAY	CAISO
Total Valley	PG&E_VLY	CAISO
Total SCE TAC Area + Valley Electric Association	SCE	CAISO
SDG&E Service Area	SDG&E	CAISO
Total BANC Control Area	SMUD	non-CAISO-CA
Total Turlock Irrigation District Control Area	TIDC	non-CAISO-CA
Imperial Irrigation District Control Area	IID	non-CAISO-CA
Total LADWP Control Area	LDWP	non-CAISO-CA
n/a	All other Zones	outside-CA

Deterministic Reliability Metrics

Deterministic studies with an hourly production cost model simulate a single realization of the time period under study, typically one year. Such studies shall report all hours and magnitudes of under-supply and over-supply *events*, be consistent with the terms and definitions in this document, and shall disaggregate events into the categories identified in the priority orders as described above in the *loss-of-load* and *over-generation* definitions, and enumerated in the table below. Under-supply *events* shall be further disaggregated into the portion attributed to capacity shortage and the portion attributed to flexibility shortage. All metrics are with respect to operations in the CAISO BAA.

[21] The forecast tables for the 2015 Integrated Energy Policy Report are found here: http://energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balencing_authority.php

Table 2: Deterministic Reliability Metrics

Metric [a]	Definition
Load-following up shortage [b]	Magnitude & hour of *under-commitment* of required *load-following* up
Non-spinning shortage [b]	Magnitude & hour of *under-commitment* of non-spinning reserve
Spinning shortage [b]	Magnitude & hour of *under-commitment* of spinning reserve
Regulation up shortage [b]	Magnitude & hour of *under-commitment* of required *regulation* up
Unserved energy [b]	Magnitude & hour of *under-commitment* of generation to serve load (effectively firm load curtailment)
Renewables curtailment energy	Magnitude & hour of economic renewables curtailment
Load-following down shortage	Magnitude & hour of *under-commitment* of required *load-following* down
Regulation down shortage	Magnitude & hour of *under-commitment* of required *regulation* down
Over-generation energy	Magnitude & hour of residual over-supply after shutting down all dispatchable resources. Also called "dump energy" or "unsolved over-generation."

[a] These guidelines are for deterministic studies with hourly production cost models reporting values in MW for each hour of a study year, where the value represents magnitude for the duration of that hour

[b] These metrics shall also be disaggregated into the portion attributed to capacity shortage and the portion attributed to flexibility shortage

Each metric described in the table above is a data series identifying the magnitude in MW and the hour of the year of each under-supply and over-supply *event*. Together they describe an outcome for a single realization of a study year of an hourly production cost model. Because the single realization of a study year provides incomplete information about the likelihood of its outcome,[22] the decision-maker should not rely on these metrics as the sole basis for determining whether procurement or other policy action is warranted. Nevertheless, hourly production cost models designed to simulate one realization of a

[22] A later section of this document describes deterministically studying several realizations of a study year where each realization still has key assumptions consistent with a single case (planning scenario). Each realization is probability weighted and called a subcase, with the intent being that the subcases reflect a plausible range of uncertainty about future conditions. In this context, the combined results from each subcase can approximate the likelihood of the single case's outcome.

study year at a time tend to include granular operational detail that is helpful for diagnosing what drivers may be causing under-supply or over-supply *events* in that particular realization of a study year.

Stochastic Reliability Metrics

Stochastic studies with an hourly production cost model effectively simulate many plausible realizations of the time period under study, typically one year, and calculate the probabilities of *events* occurring within that time period. A stochastic study shall report results using the metrics: Loss of Load Expectation, Loss of Load Hours, normalized Expected Unserved Energy, Expected Renewables Curtailment, and Expected Over-generation. Each metric is described below. The studies and calculation of the metrics shall be consistent with the terms and definitions in this document. For the metrics measuring instances of *loss-of-load*, the metrics shall be further disaggregated into the portion attributed to capacity shortage *loss-of-load* and the portion attributed to flexibility shortage *loss-of-load*. All metrics are with respect to operations in the CAISO BAA.

The **Loss of Load Expectation** (LOLE) metric quantifies the expected frequency of *loss-of-load events* per year where one or more instances of *loss-of-load* occurring within the same day regardless of duration shall count as one *loss-of-load event* (i.e. day). Calculated in this way, the LOLE metric can be compared to a reference point such as the industry probabilistic reliability standard of "one expected day in 10 years,"[23] i.e. an LOLE of 0.1. This comparison can provide insight into the reliability level of the electric system being modeled.

The **Loss of Load Hours** (LOLH) metric quantifies the expected number of hours of *loss-of-load* per year where one or more instances of *loss-of-load* occurring within the same hour regardless of duration shall count as one *loss-of-load* hour. The LOLH metric provides supplemental information on the reliability level of the electric system being modeled. However, industry experience offers no obvious reference LOLH value for comparison.

The **Expected Unserved Energy** (EUE) metric quantifies the expected unserved energy per year from all instances of *loss-of-load*. EUE is normalized by dividing by the total net energy to serve load per year. This results in an expected percentage of load that cannot be served per year due to inadequate supply.[24] The normalized EUE metric provides supplemental information on the reliability level of the electric system being modeled. However, industry experience offers no obvious reference normalized EUE value for comparison. A reference value could be developed by calculating the average percentage of unserved energy out of total annual net energy served for several historical years that are known to have satisfactory reliability performance.

[23] This generally means that the electric system shall be planned such that electric service interruptions due to inadequate supply are expected to occur only one day in ten years.

[24] Normalized EUE is sometimes also called LOLP – Loss of Load Probability because it represents a probability of loss of load.

This document defines **Expected Renewables Curtailment** as a metric that quantifies the expected total economic renewables curtailment energy in a year.

This document defines **Expected Over-generation** as a metric that quantifies the expected total *over-generation* energy in a year. *Over-generation* as described earlier, is the residual over-supply occurring when no more dispatchable resources can be turned down and off and can include *under-commitment* of some *operating reserves*.

The table below summarizes the metrics that stochastic studies with an hourly production cost model shall report, including required reporting of statistical distribution information about each metric.

Table 3: Stochastic Reliability Metrics

Metric [a] [c] [d]	Event definition	How events are counted [e]	Reference value
LOLE [b]	Supply < Load + spinning reserves + required regulation up	One or more instances of *loss-of-load* occurring within the same day count as one *event* in the LOLE calculation	0.1
LOLH [b]	Same as LOLE	One or more instances of *loss-of-load* occurring within the same hour count as one hour in the LOLH calculation	N/A
Normalized EUE [b]	Same as LOLE	The unserved energy from all *loss-of-load* instances count toward EUE	N/A
Expected Renewables Curtailment (GWh)	Any market dispatched renewables curtailment	All economic renewables energy curtailed counts toward this metric	N/A
Expected Over-generation (GWh)	Residual over-supply after all dispatchable resources turned down and off	All *over-generation* energy counts toward this metric	N/A

[a] These guidelines are for stochastic studies with hourly production cost models reporting expected values over a year

[b] Metrics and related statistics shall also be disaggregated into the portion attributed to capacity shortage *loss-of-load* and the portion attributed to flexibility shortage *loss-of-load*

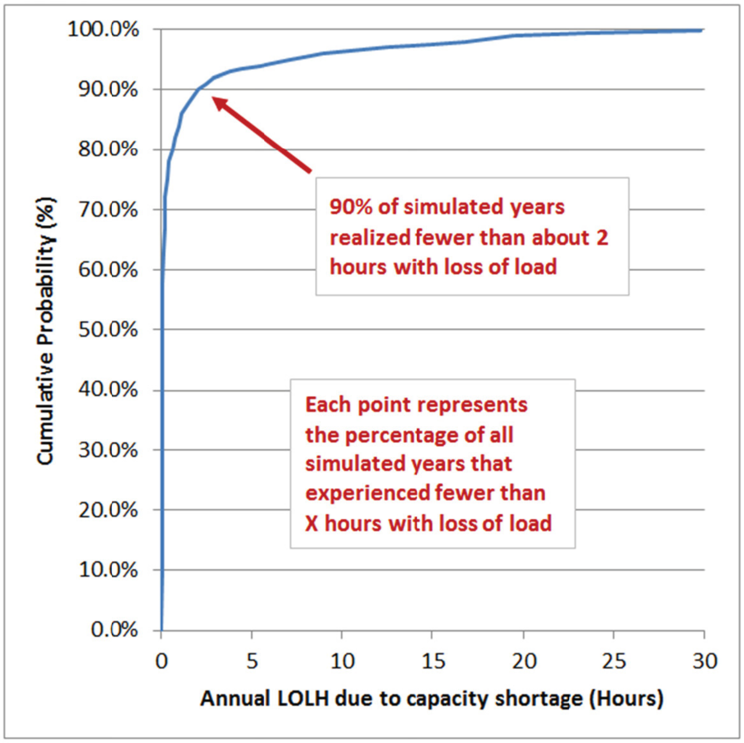
[c] Reported data shall include at a minimum, for all five metrics, plots of cumulative probability vs. metric and the underlying data tables

[d] Reported data shall include at a minimum, for all five metrics, plots of (1) percentage of all *events* vs. weekday hour of calendar month, (2) percentage of all *events* vs. weekend&holiday hour of calendar month, (3) percentage of all *events* vs. calendar month, as well as the underlying data tables

[e] To the extent a model is capable of discerning events that occurred over only portions of an hour, it should account for that finer granularity, for example, when unserved energy occurs only for portions of an hour, that granularity should be reflected in the reported unserved energy statistics

The following figures serve as example plots illustrating the statistical distribution information and other data reporting requirements specified in the notes of the table above. The data shown do not represent any actual analysis and purely serve to illustrate format. For the three *loss-of-load* related (LOLE, LOLH, normalized EUE) metrics' cumulative distributions, at least three versions of plots for each metric are required: (1) portion due to capacity shortage, (2) portion due to flexibility shortage, (3) both portions counted together for overall *events* statistics. Figure 1 is an example.

Figure 1: Example Cumulative Probability vs. Metric



For the three *loss-of-load* related (LOLE, LOLH, normalized EUE) metrics' *event* frequency distributions, the disaggregation into portions due to capacity shortage and flexibility shortage can be shown as one stacked bar chart for each metric type as illustrated in Figure 2. All of the segments of bars add up to 100 percent in both Figure 2 and Figure 3. Figure 2 illustrates an example *event* frequency distribution across calendar months and Figure 3 illustrates an example across weekday hours of a calendar month (in this example, the economic renewables curtailment metric would have 25 frequency distribution plots, a weekday version and a weekend/holiday version for each calendar month, plus the version showing distribution across calendar months). These figures are examples – the notes in Table 3 above enumerate all the combinations of plots and underlying data tables that should be reported.

Figure 2: Example Event Frequencies Across Calendar Months

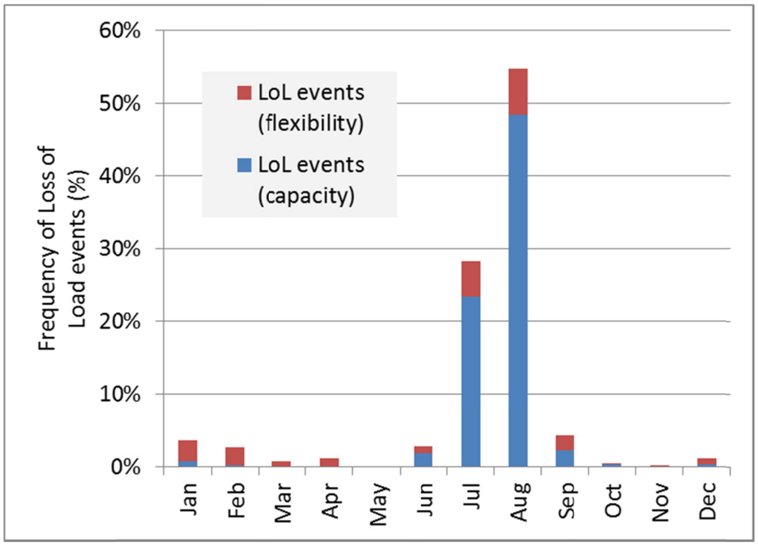
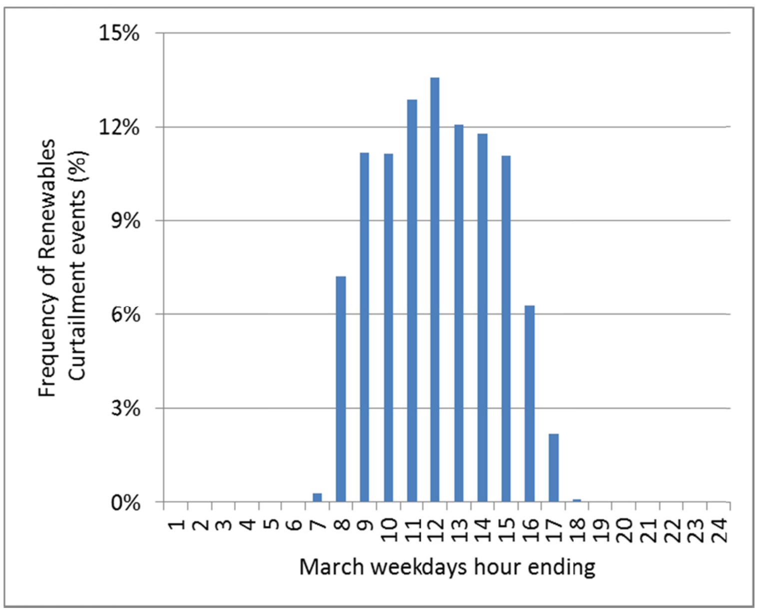


Figure 3: Example Event Frequencies Across Weekday Hours of a Calendar Month



The metrics described in Table 3 indicate the likelihood of under-supply or over-supply *events* along several dimensions, when modeling the probability-weighted range of conditions included in a stochastic study with an hourly production cost model. Assuming that the stochastic study captures a realistic and comprehensive range of uncertainty in future conditions, decision-makers could use these metrics to judge if the risk of reliability problems is high enough to warrant procurement or other policy action. However, this document does not specify in advance any particular risk level that any of these metrics must target. Determination of which metric(s) should be held to what risk level(s) should occur within the IRP-LTPP or related Commission proceeding. The metrics as defined above are simply a consistent way to quantify the range of risks that decision-makers should consider.

Although this document does not recommend any particular risk level (or planning standard) for any of the stochastic metrics, it recognizes the value of specifying one common reference point for comparison across different studies and/or models. The table above identifies 0.1 LOLE as a reasonable reference point for comparison to the actual LOLE reported by the model because 0.1 LOLE can be translated to the industry planning standard of "one-day-in-ten-years" in the manner described above. However, note that just because 0.1 LOLE is a convenient reference point does not mean it is an appropriate planning standard. For example, the "one-day-in-ten-years" industry standard was traditionally based on studies that examine system stress only at peak hour conditions, ignoring possible stress conditions occurring at other hours.[25] However, the stochastic studies with hourly production cost models discussed in this document may be designed to assess all hours of system operation in order to consider both peak capacity and flexibility needs. This means that applying the "one-day-in-ten-years" standard to studies that assess all hours of the year may be more conservative than previous industry practice (i.e. enforcing a higher reliability level). Hence, 0.1 LOLE is useful as a reference point for comparison to actual LOLE, but 0.1 LOLE is not necessarily a suitable target for Commission decision-making.

Model Output Requirements

Greenhouse Gas Emissions Reporting

Greenhouse gas (GHG) emissions are a critical model output to assess whether California is likely to achieve its GHG emissions reduction goals under a range of alternative futures. Furthermore, due to concerns about shifting emissions between California and the rest of the WECC area, models should also report emissions from the rest of the WECC area in addition to California-specific emissions. Granularity by hour, resource type, and location is also important to understand where emissions are coming from and what procurement or policy changes may be most effective at reducing emissions. For deterministic studies, this level of granularity can be achieved by capturing hourly fuel use and generation data by resource type and location. Capturing and reporting fuel use and generation data rather than just emissions will aid in model transparency and validation, and enable post-processing to calculate GHG emissions under alternative GHG accounting regimes. For stochastic studies, highly granular GHG emissions reporting may not be practical due to the large volumes of data and computational intensity inherent in such studies. In light of these considerations, the GHG reporting requirements for production cost models as specified in the following table shall be used. These are minimum requirements and to the extent studies can report further relevant or more granular details with reasonable additional effort, they should.

[25] See discussion on probabilistic reliability modeling to calculate ELCC on pages 7-8 of this document: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6570

Table 4: GHG Emissions Reporting

Output	Study type	Temporal resolution	Disaggregate (breakout) by
Fuel combustion (MMBtu)	Deterministic	Hourly	Fuel type [a], Resource type [b], Zone [c]
GHG emissions (million metric tons CO2e)	Deterministic	Monthly	Resource type [b], Region [d]
Expected GHG (million metric tons CO2e) [e] [f]	Stochastic	Annual	Region [d]

[a] Fuel type: coal, oil, natural gas, nuclear, biomass, biogas, other

[b] Resource type (only emissions producing): steam turbine, gas turbine, combined cycle, cogeneration, nuclear, bioenergy, imports, other

[c] Zone: Each geographic area modeled to have no transmission constraints within the area, for example, PG&E_VLY, LDWP, or TIDC

[d] Region: CAISO, non-CAISO-CA, and outside-CA, where CAISO is all zones comprising the CAISO balancing authority area, non-CAISO-CA is all zones inside of California excluding the CAISO zones, and outside-CA is all zones outside of California

[e] Stochastic studies perform statistical analysis and report an "expected value" for a given output

[f] Reported data shall include plots of cumulative probability vs. GHG emissions and the underlying data tables for each of three regions: CAISO, non-CAISO-CA, outside-CA

Bioenergy Emissions Accounting Conventions

The California Air Resources Board (ARB) is the lead state agency that determines how bioenergy emissions should be treated when accounting for state GHG emissions. Current guidance in ARB's implementation of the AB 32 cap and trade program directs that entities producing bioenergy emissions shall report carbon emissions to the ARB in separate categories and only fossil-based carbon emissions are subject to cap and trade program caps. In other words, the ARB's cap and trade regulation does not impose a compliance obligation on emitters using verified biomass fuels.[26] This means that electricity production from verified biomass fuels will be counted as carbon neutral.

This document specifies a common accounting convention for GHG emissions from biofuels in production cost modeling of the electric system so that the results of different models will be comparable. To this end, total GHG emissions shall be reported assuming that generation from verified

[26] See Section 95852.2 of Subchapter 10 Climate Change, Article 5, of the California Code of Regulations for a description of emissions without a compliance obligation: http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm

biomass fuels are carbon neutral. This aligns with current ARB treatment in the cap and trade program. Should the ARB modify its treatment of verified biofuels, the CPUC will take action and modify this document to align with ARB treatment. This document's required carbon neutral treatment is solely for the purpose of having a common accounting convention in production cost modeling that informs Commission decisions with regards to electric resource planning and procurement. It does not imply any factual finding on whether combustion of different types of biofuels would truly result in net positive or net negative carbon emissions.

Although this document directs modelers to calculate total GHG emissions using the convention that verified biofuels are carbon neutral, the models must still report fuel consumption and generation data by resource type as outlined elsewhere in this document. This preserves the necessary information to conduct further analysis using alternative GHG accounting conventions for biofuels or any other fuels should such analysis be deemed desirable during the course of Commission proceedings.

Deterministic Studies Other Outputs

Deterministic studies with an hourly production cost model shall report the reliability metrics and GHG-related outputs identified above and additionally the outputs and parameters itemized in the table below. These are minimum requirements and to the extent studies can report further relevant or more granular details with reasonable additional effort, they should.

Table 5: Other Outputs from Deterministic Studies

Parameter/Output	Temporal resolution	Disaggregate (breakout) by
Load (MW)	Hourly	Zone [b]
Operating reserves requirements (MW)	Hourly	Reserve type, CAISO BAA only
Operating reserves committed (MW)	Hourly	Reserve type, Resource type [a], CAISO BAA only
Generation (MW)	Hourly	Resource type [a], Zone [b]
Resource capacity on outage (MW)	Hourly	Resource type [a], Zone [b]
Resource capacity available (not on outage) (MW)	Hourly	Resource type [a], Zone [b]
Energy prices ($/MWh)	Hourly	Zone [b]
Operating reserves prices ($/MWh)	Hourly	Reserve type, CAISO BAA only
Frequency response constraint shadow prices ($/MWh)	Hourly	CAISO BAA only
Storage charging and discharging levels (MW)	Hourly	Resource type [a], Zone [b]
Net imports into CAISO BAA (MW)	Hourly	CAISO BAA only
Production costs (millions of $)	Hourly	Zone [b]

[a] Resource type: steam turbine, gas turbine, combined cycle, cogeneration, nuclear, conventional hydro, pumped storage, other storage, BTM PV, small hydro RPS, solar PV, other solar, wind, geothermal, bioenergy, other renewable, demand response, imports into CAISO BAA, other

[b] Zone: Each geographic area modeled to have no transmission constraints within the area, for example, PG&E_VLY, LDWP, or TIDC

Stochastic Studies Other Outputs

Stochastic studies with an hourly production cost model shall report the reliability metrics and GHG-related outputs identified above and additionally the outputs itemized in the table below. Nearly all of these outputs are iteration-specific results, i.e. the results from individual draws in the underlying Monte-Carlo simulation of a stochastic study. Capturing key data from each hour of each (year-long) iteration can facilitate a clearer understanding of the impact of underlying variables on model results and aid model validation and transparency. These are minimum requirements and to the extent studies can report further relevant or more granular details with reasonable additional effort, they should.

Table 6: Other Outputs from Stochastic Studies

Parameter/Output	Temporal resolution	Disaggregate (breakout) by
Load (MW)	Hourly	Region [b]
Operating reserves requirements (MW)	Hourly	Reserve type, CAISO BAA only
Operating reserves committed (MW)	Hourly	Reserve type, Resource type [a], CAISO BAA only
Operating reserves shortages (MW)	Hourly	Reserve type, CAISO BAA only
Unserved load (MW)	Hourly	CAISO BAA only
Generation (MW)	Hourly	Resource type [a], Region [b]
Resource capacity on outage (MW)	Hourly	Resource type [a], Region [b]
Resource capacity available (not on outage) (MW)	Hourly	Resource type [a], Region [b]
Net imports into CAISO BAA (MW)	Hourly	CAISO BAA only
Production costs (millions of $)	Hourly	Region [b]

[a] Resource type: steam turbine, gas turbine, combined cycle, cogeneration, nuclear, conventional hydro, pumped storage, other storage, BTM PV, small hydro RPS, solar PV, other solar, wind, geothermal, bioenergy, other renewable, demand response, imports into CAISO BAA, other

[b] Region: CAISO, non-CAISO-CA, and outside-CA, where CAISO is all zones comprising the CAISO balancing authority area, non-CAISO-CA is all zones inside of California excluding the CAISO zones, and outside-CA is all zones outside of California

Modeling Method Requirements

Use of Deterministic, Stochastic, or a Combination of Both Study Approaches

There is value in both the deterministic and stochastic study approaches with production cost models that were explored in the 2014 LTPP proceeding, with each approach having different strengths.

Deterministic studies with production cost models have been vetted through years of use and are usually designed to simulate one realization of a study year at a time, thus making them generally easier to understand. They are usually more conducive to producing, saving, organizing, and analyzing considerable detail regarding simulated system operations. This in turn facilitates diagnosis of complex operational causes of simulated under-supply and over-supply events. Deterministic studies may be useful for assessing the cumulative annual amount of recurrent events such as renewable curtailment.

Deterministic studies are also useful for comparing the relative difference in results of several "what-if" cases or examining the sensitivity of a single variable. Here, a case represents a fixed infrastructure portfolio plus a fixed set of assumptions about future conditions, e.g. load levels, fuel prices, and weather, thus representing a single realization of the future. However, a deterministic study that examines one realization of the future does not provide sufficient information related to the likelihood of its outcomes, especially when considering the uncertainty associated with many of the study inputs. For this reason, deterministic study results from one case are generally not comparable to stochastic study results or probabilistic reliability standards.

Stochastic study approaches are mature and widely used in other contexts but have only recently been considered for development of capacity and flexibility sufficiency studies by the Commission's LTPP proceeding. Although stochastic studies may be complex and/or require greater computational resources than deterministic studies, they can be designed to systematically account for a wide, diverse, and realistic range of future conditions and to report expected (average) results as well as the likelihood of extreme or rare outcomes. Stochastic study results can be used to establish or be compared to probabilistic reliability standards.

A combination of these two study approaches can provide the Commission with more complete information about future system reliability and performance. At the same time, different parties may prefer to assess the future system using one or the other study approach. In order to ensure that studies from different parties using different approaches can be compared, the remainder of this document establishes a set of requirements for both deterministic and stochastic study approaches (methods) and requires that all parties must at a minimum study a CPUC-designated *Reference* case.

Requirements for Deterministic Methods

Parties conducting deterministic studies are required at a minimum to study the *Reference* case expanded into a set of several deterministic studies of *subcases*. "Cases" as used in this document, equate to planning scenarios designed to represent alternative policy-driven visions of the future, for example alternative resource mixes or alternative levels of CAISO expansion. In contrast, *subcases* are an expansion of a single case intended to represent policy-agnostic uncertainty within that case, for example future weather patterns and climate change impacts. More specifically, *subcases* are a systematically constructed and weighted set of deterministic studies covering a sufficiently diverse range of realistic future conditions that could reasonably occur within the one case associated with the *subcases*.[27] Beyond studying the required *Reference* case with required expansion into *subcases*, parties may choose to additionally study alternative cases, with or without expansion into *subcases*.

The detailed requirements for deterministic studies with or without expansion into *subcases* follow.

A. A case represents one combination of realistic hourly load plus wind and solar meteorological conditions, unless expanded into *subcases*. Each *subcase* represents a different combination of

[27] The study of a weighted set of deterministic *subcases* is in fact a simplified stochastic study. Determining the *subcases* and weights can be challenging and subjective.

realistic hourly load plus wind and solar meteorological conditions. A case or its *subcases* shall be developed from public, historical data on loads and the meteorological conditions driving wind and solar generation (e.g. wind speed, solar irradiance, and cloud cover).[28] The load plus wind and solar meteorological condition for each hour of a case or its *subcases* shall be derived from historically co-occurring conditions. Available locational granularity in the historical data shall be preserved to the extent practicable.[29]

B. Based on known, available, and co-occurring historical data, this document requires <u>four *subcases*</u> representing load and meteorological conditions that co-occurred in <u>years 2007 through 2010</u>. Each *subcase* is weighted equally. Modelers may optionally present additional results using alternative weightings for each *subcase*.

C. The set of *subcases* associated with any case shall be consistent with the particular load forecast and wind and solar generator portfolios established for that case. The steps for synthesizing a case or its *subcases* from historical data shall be sufficiently documented by the party conducting the modeling such that the work can be replicated from the source data. The documentation should explain each mathematical step, justify its reasonableness, and make use of numerical examples as an explanatory aid. The synthesis of a case or its *subcases* from historical data must adhere to the following:

1. The installed capacity and technical/locational attributes of resources remain fixed by the case's resource portfolio and therefore fixed across each of the case's *subcases*.

2. The synthesized future hourly load shapes in a case or its *subcases* must be consistent with the single annual energy and peak forecasts of the case under study (e.g. year 2026 forecast), yet reflect the variability and load factor in the historical load data upon which the case or its *subcases* are based.

3. The synthesis of future hourly load shapes from historical load data must reasonably account for the effects of year over year load growth, differences between weekdays and weekends/holidays, and demand-side resources (e.g. historical BTM solar PV production and

---

[28] As of August 2016, public data includes but is not limited to the following sources:

- FERC Form 714 historical hourly load data: http://www.ferc.gov/docs-filing/forms/form-714/data.asp
- NREL WIND Toolkit containing wind meteorological conditions and turbine power for more than 126,000 sites in the continental U.S. for 2007–2013 http://www.nrel.gov/electricity/transmission/wind_toolkit.html
- NREL SIND Toolkit containing one year (2006) of 5-minute solar power and hourly day-ahead forecasts for 6,000 simulated PV plants in the U.S. http://www.nrel.gov/electricity/transmission/sind_toolkit.html
- National Solar Radiation Database (1991-2010) http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2010/
- WECC Transmission Expansion Planning 2026 Common Case V1.3 https://www.wecc.biz/SystemAdequacyPlanning/Pages/Datasets.aspx

[29] For example, hourly solar meteorological conditions that historically occurred in a particular area of Southern California shall be used to synthesize the hourly generation profiles for solar generation located in the same area

demand response calls) that are present in historical load data. Additionally, future hourly load shapes may need to consider potential load drivers that were not present in historical load data, for example, newer demand side measures and technologies, higher penetration of electric vehicles, or changes in rate designs).

Requirements for Stochastic Methods

Parties conducting stochastic studies are required to study the *Reference* case. “Cases” as used in this document, equate to planning scenarios designed to represent alternative policy-driven visions of the future, for example alternative resource mixes or alternative levels of CAISO expansion. In contrast, the stochastic input distributions of a stochastic study of a given case represent policy-agnostic uncertainty within that case, for example future weather patterns and climate change impacts. Thus, the stochastic input distributions are analogous to the set of deterministic *subcases* described in the preceding subsection of this document, except that the stochastic input distributions equate to hundreds or thousands of *subcases* and should be inclusive of the set of deterministic *subcases* described above. If a party using a stochastic study method wishes to study one or more alternative cases, it may do so in addition to the required *Reference* case.

Additionally, parties conducting stochastic studies are also required to conduct deterministic studies for each of the deterministic *subcases* of the *Reference* case, as described in the preceding subsection. This additional exercise enables a more comprehensive comparison between the study methods and models of different parties, regardless of whether a party’s analysis uses a deterministic or stochastic approach. The comparison exercise, being a set of deterministic studies, shall follow all the deterministic metrics and outputs reporting requirements outlined earlier in this document. To the extent a model has technical limitations that make it impossible to produce all of the required deterministic outputs, the modeler shall explain the limitation for each output that cannot be produced and provide the most similar feasible output.

The detailed requirements for constructing the stochastic input distributions of a stochastic study and any other relevant requirements follow. These requirements apply to the study of any case including the *Reference* case.

A. For a stochastic study of a given case, the resource portfolio (mix) is fixed and does not vary within the study. The stochastically varying elements only include resource outages, load, and wind and solar meteorology. The sponsor of a stochastic study shall explain and document the study’s method of constructing and using resource outage distributions. Requirements for distributions of hourly load and wind and solar generation are explained below.

B. If a stochastic study measures a system reliability level that falls short of some desired target, it may be useful to quantify what must be added to the system to improve the reliability level to the desired target.[30] This can be done by progressively adding some generic resources to the model and

[30] If a stochastic study measures a system reliability level that equals or exceeds some desired target, then the system is sufficiently reliable

then redoing the study until the reported reliability level reaches the desired target. The amount of added generic resources is one way of quantifying how short the system is from a desired reliability target. For example, if a stochastic study measures 0.25 LOLE, then a modeler can progressively add generic resources and rerun the study until the reported reliability level reaches the desired target, for example 0.1 LOLE. To ensure consistency and comparability across different studies and/or models, the generic resources to be added by all modelers shall be "perfect capacity" as defined in the CPUC's Resource Adequacy proceeding's (R.14-10-010) "Effective Load Carrying Capability of Wind and Solar Resources in the CAISO Balancing Authority and Resetting the Reserve Margin for Resource Adequacy Obligations" Energy Division proposal.[31] Perfect capacity is essentially a model proxy for a resource with no operating constraints, for example it is always available, starts up instantly, and has no minimum operating level.

C. The distributions of hourly load and wind and solar generation synthesized for a stochastic study of any case shall be fundamentally derived from and statistically consistent with public, historical data on loads and the meteorological conditions driving wind and solar generation (e.g. wind speed, solar irradiance, and cloud cover).[32] The distributions shall retain statistical cross correlations that exist in the historical data. Available locational granularity in the historical data shall be preserved to the extent practicable.[33] The sponsor of a stochastic study must provide documentation demonstrating compliance with these requirements.

D. The hourly load and wind and solar generation distributions synthesized for a stochastic study of any case shall be consistent with the particular load forecast and wind and solar generator portfolios established for that case. The steps for synthesizing the distributions of future hourly load and wind and solar generation from historical data shall be sufficiently documented by the party conducting the modeling such that the work can be replicated from the source data. The documentation should explain each mathematical step, justify its reasonableness, and make use of numerical examples as an explanatory aid. The synthesis of hourly load and wind and solar generation distributions from historical data must adhere to the following:

1. The variability in the synthesized distributions for wind and solar generation arises primarily from the variation present in historical meteorology. The installed capacity and technical/locational attributes of resources remain fixed by the case's resource portfolio and therefore fixed across the case's distributions of wind and solar generation.

---

[31] Perfect capacity is defined in Table 4 of the March 25, 2016 Energy Division proposal posted here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10599

[32] See footnote in preceding subsection citing a list of public data (not exhaustive)

[33] For example, hourly solar meteorological conditions that historically occurred in a particular area of Southern California shall be reflected the distribution of future hourly generation profiles for solar generation located in the same area

2. The distribution of synthesized hourly load shall have its annual energy mean value and annual peak mean value be consistent with the single annual energy and peak forecasts of the case under study (e.g. year 2026 forecast), yet reflect the variability and load factor in the historical load data upon which the distribution is based.

3. The synthesis of future hourly load shapes from historical load data must reasonably account for the effects of year over year load growth, differences between weekdays and weekends/holidays, and demand-side resources (e.g. historical BTM solar PV production and demand response calls) that are present in historical load data. Additionally, future hourly load shapes may need to consider potential load drivers that were not present in historical load data, for example, newer demand side measures and technologies, higher penetration of electric vehicles, or changes in rate designs).

Modeling and Validating Load-Following and Regulation Requirements

Whether using deterministic or stochastic approaches, hourly production cost models usually model hourly load following reserve and regulation commitment requirements. These operating reserve types were described earlier in this document and are generally purposed with balancing routine load and generation variability inside of the hourly market dispatch intervals of the production cost model, as well as forecast error regarding the next hour's load and generation. As mentioned earlier in this document, how much load following reserve and regulation to commit for each hour is a question of increasing importance because of the perception that more reserves may be necessary to manage the increasing variability introduced by higher penetrations of wind and solar resources on the electric grid. However, validating whether the committed reserve amounts are adequate can be challenging because the consequences of too little or too much reserves may not be explicitly simulated in an hourly model.

The CPUC is aware of several alternative approaches to calculating hourly load following reserve and regulation requirements. The CAISO's deterministic study in the 2014 LTPP proceeding (R.13-12-010) used an exogenous stochastic analysis referred to as the "Step 1" calculation.[34] In the same proceeding, SCE's stochastic study used a somewhat simpler method assuming a fixed percentage of load for regulation requirements and an analysis of hourly ramping and forecast error to determine load following requirements.[35] The CPUC's Resource Adequacy proceeding's "Effective Load Carrying Capability stochastic modeling Energy Division staff proposal" used percentages of hourly load to calculate requirements.[36] The California Energy Systems for the 21st Century "Flexibility Metrics and

---

[34] The "Step 1" calculation analyzes distributions of hourly and sub-hourly forecast error and variability in net load (i.e. load net of wind and solar generation). Technical background on this approach is available here: http://www.caiso.com/Documents/DraftTechnicalAppendices_RenewableIntegrationStudies-OperationalRequirementsandGenerationFleetCapability.pdf

[35] Described in the "Third Revised Appendix A – Technical Appendix for 2014 Long Term Procurement Plan High Load Scenario", which was served to parties of R.13-12-010 on December 11, 2014

[36] Described in "Resource Adequacy Probabilistic Reliability Modeling Inputs and Assumptions" posted here: http://www.cpuc.ca.gov/General.aspx?id=6265

Standards Project" used the same underlying model as the CPUC's Resource Adequacy proceeding but employed a refinement to the load following calculation.[37] NREL's Eastern Wind Integration and Transmission Study evaluated changes to various operating reserves required at higher wind penetrations.[38]

To enable comparison of results from different models, this document requires that hourly production cost models use the following method for calculating hourly load following reserve and regulation commitment requirements.

- Hourly regulation up requirement: 1.5% of hourly forecast load
- Hourly regulation down requirement: 1.5% of hourly forecast load
- Hourly load following up reserve requirement: 2.5% of hourly forecast load + hourly forecast net load change (where net load is load net of wind and solar generation, including BTM solar, and net load change is from start of hour to end of hour)
- Hourly load following down reserve requirement: 1.5% of hourly forecast load

This required calculation method applies to both deterministic and stochastic study approaches. Modelers who wish to use an alternative calculation method may do so in an additional sensitivity study.

Additionally, this document requires the following validation steps to help establish whether a study's implementation of the required method or an alternative method is reasonable and produces plausible results.

A. Define what capabilities hourly load following reserves and regulation represent in a chosen production cost modeling approach. For example, in Model A, X MW of load following up is defined as the ability and headroom to ramp upward X MW in Y minutes. Define what resource types (e.g. only dispatchable units for upward, and both dispatchable units and wind/solar for downward) can provide this capability and what operational state the resource must be in to do so.

B. If using an alternative method, explain and justify this method of calculating hourly load following reserves and regulation requirements. Explain each of the mathematical steps for calculating these requirements in sufficient detail such that the work can be replicated from source data, for example through the use of numerical examples of representative modeled hours. Explain what variability these requirements are intended to address. Identify and provide all source data.

C. Regardless of method, separately calculate the hourly load following reserves and regulation requirements under the following conditions:
    (a) Only designed to handle load variation alone, i.e. no wind generation, no solar (and no BTM PV) generation

[37] Briefly described in a CPUC workshop presentation, January 6, 2016, posted here: http://www.cpuc.ca.gov/General.aspx?id=11678

[38] http://www.nrel.gov/docs/fy11osti/47078.pdf

(b) Only designed to handle load plus wind generation variation alone, i.e. no solar (and no BTM PV) generation
(c) Only designed to handle load plus solar (including BTM PV) generation variation alone, i.e. no wind generation
(d) Designed to handle load plus wind and solar (including BTM PV) generation variation (i.e. same as what is used in the production cost model)

For a given method of calculating hourly load following reserves and regulation requirements, the different calculated requirements under each of the conditions (a) through (d) shall be compared to each other as an indication of how much additional load following and regulation is introduced by the need to handle wind or solar variability. Because of possible cross correlations, it is not expected that the requirements designed for load variation alone, plus the additional amounts required to handle wind and solar variation individually, would equate to (d).

Minimum Generation Constraints

The Regional Generation Requirement and the Frequency Response Constraint described in the May 2016 LTPP Assumptions and Scenarios Assigned Commissioner's Ruling[39] are essentially hourly production cost model constraints serving as crude proxies for real reliability requirements to have certain minimum amounts of generation resources with certain attributes online at all times, hence the term "minimum generation constraints." The constraints are intended to ensure a production cost model operates resources reflecting the sufficient provision of required local capacity, inertia, frequency response, reactive power, and voltage stability.

Hourly production cost models shall use the Frequency Response Constraint specified in the May 2016 LTPP Assumptions and Scenarios Ruling or its successor document. The CAISO BAA only has a Frequency Response Constraint and does not have a Regional Generation Requirement. A Regional Generation Requirement (but no separate, explicit Frequency Response Constraint) applies to all other non-CAISO BAAs in California (i.e. the zones: IID, LADWP, SMUD, and TIDC). The Regional Generation Requirement shall be implemented as a model requirement to have at least 25 percent of hourly load met with generation located in the same zone as the load, excluding renewables, demand response, and battery storage. This constraint is inherited from the models used in the 2014 LTPP proceeding.

(END OF ATTACHMENT)

[39] The May 17, 2016 Ruling here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11673